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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CAL

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.

Rulemaking 14-08-013
(Filed August 14, 2014)

VOTE SOLAR'S RESPONSES TO QUESTIONS POSED IN THE COMMISSION'S ORDER INSTITUTING RULEMAKING

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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

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On August 20, 2014, the Commission issued an Order Instituting Rulemaking ("OIR") in the above-captioned proceeding. The OIR invites interested parties to respond to 16 questions and address the scope, schedule and other procedural issues. Vote Solar respectfully submits the following responses to the questions presented by the Commission in the OIR. Vote Solar provides no comment at this time addressing scope, schedule and other procedural issues, however, Vote Solar reserves the right to comment on such issues in its reply comments, which the OIR states will be accepted through September 22, 2014. Vote Solar appreciates the opportunity to weigh in on the important questions set forth in the OIR.

1) **What specific criteria should the Commission consider to guide the IOUs' development of DRPs, including what characteristics, requirements and specifications are necessary to enable a distribution grid that is at once reliable, safe, resilient, cost-efficient, open to distributed energy resources, and enables the achievement of California's energy and climate goals?**

In guiding the development of the electric IOUs' Distribution Resource Plans ("DRPs"), Vote Solar believes the Commission should focus on providing a modernized electric grid that (1) serves as a backbone to facilitate access to Distributed Energy Resources ("DERs")[1]; (2) provides open access to DER providers; (3) facilitates information transparency and a greater

[1] A.B. 327 defines "distributed resources" as including distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies.

diversity of energy choices for customers; (4) and expands options for renewable-energy procurement for all customers, including larger corporate, institutional and government entities with clean-energy commitments, goals or interests. While achieving these goals requires certain policy choices that fall outside the scope of this proceeding, the establishment of a modernized grid will allow policymakers to make decisions that support these goals.

With respect to the *characteristics* necessary to enable a distribution grid that satisfies the description posed by Question 1, the existing three large electric IOUs are in the best position to manage the distribution grid. However, they should do so with a mandate to respond to customer demand for DERs, provide open access to their distribution facilities (including the continued accommodation of customer-side generation), and utilize appropriate planning practices that account for and embrace DER expansion. California should maintain its current policy of rate basing distribution system upgrades necessary to accommodate smaller customer-side DG. This will allow the IOUs to respond effectively to the expansion of customer-sited solar DG, while facilitating the achievement of California's energy and climate goals through private investment.

The cost of achieving a modernized distribution grid can be equitably distributed by using existing rate-design tools. Rates, in turn, should provide clear price signals to market participants that result in cost-efficient outcomes, should promote a more-efficient use of IOU infrastructure, and should be calibrated to avoid unnecessary infrastructure investments. In general, the Commission should avoid embracing new or modified rate designs that discourage customers from investing in energy efficiency and on-site DG, including rate structures that favor fixed charges over volumetric charges.

With respect to the *requirements* necessary to enable a distribution grid that satisfies the description posed by Question 1, reliability and safety should continue to be maintained by adhering to the current applicable technical standards, including standards established by IEEE, ANSI, SADI/SAFI and NERC. These standards are currently enforced as part of the interconnection process, incorporated into Rule 21, for DG and energy-storage systems. System design should facilitate compliance with Rule 2.

With respect to the *specifications* necessary to enable a distribution grid that satisfies the description posed by Question 1, the establishment of a fully modernized grid is key. California has made a good start, in that it has already adopted a number of best practices that have positioned it near the front of the grid-modernization movement in the United States. However, more can be done. Specifically, we believe the Commission should focus on three goals: (1) facilitating and expanding customer choice; (2) promoting DER development in locations that have lower integration cost; and (3) considering DERs as an alternative to transmission and distribution ("T&D") upgrades and expenditures.

2) What specific elements must a DRP include to demonstrate compliance with the statutory requirements for the plan adopted in AB 327?

Public Utilities Code Section 769, established by A.B. 327, states explicitly what must be included in each IOU's DRP. Each proposal shall:

- Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.
- Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
- Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.
- Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

Vote Solar's proposals in these responses are fully consistent with these statutory requirements.

3) What specific criteria should be considered in the development of a calculation methodology for optimal locations of DERs?

We believe the optimal location of DERs varies by one or more of three possible goals or DER applications: (1) where customers would like to integrate DERs, or "Customer Responsiveness" (2) where DERs can be integrated at a low cost, or "Low-Cost Integration;" and (3) where DERs can maximize grid benefits, or "Benefits Maximization."

In the case of Customer Responsiveness, customers determine where and when they want to utilize DERs, and IOUs could be compensated based on their responsiveness to facilitating customer access to DERs. Examples of DERs included in this category are customer-sited DG, community or shared PV projects, charging facilities for electric vehicles, energy-storage facilities, and automation for homes and other buildings.

In the case of Low-Cost Integration, DERs would be integrated strategically and where the cost of doing so would be relatively low. These projects could be co-located with load, located within load centers, and/or located near sub-station facilities. Relevant criteria to consider for such projects include distribution line voltage, distance to load, and proximity to sub-stations. Low-Cost Integration projects would facilitate the State's existing DG policy goals by encouraging DG development at the lowest overall cost.

In the case of Benefits Maximization, DERs would be integrated strategically and where doing so would prevent or defer necessary upgrades to T&D facilities. Relevant criteria to consider for these projects include the extent of avoided or deferred system upgrades, and the reliability of DER availability. With respect to the latter, the development of certain combinations of DERs, including microgrids or DG systems combined with storage, could be supported.

While these three goals are not mutually exclusive, they do not fully overlap. For example, DERs that support Customer Responsiveness would often also support Low-Cost Integration, but DERs that support Low-Cost Integration would not necessarily also support Customer Responsiveness. In addition, DERs that support Benefits Maximization might not also support Customer Responsiveness or Low-Cost Integration, but the benefits yielded by DERs that support Benefits Maximization could justify higher integration costs if significant expenses can be avoided or deferred.

4) What specific values should be considered in the development of a locational value of DER calculus? What is optimal means of compensating DERs for this value?

Our response to Question 3 describes three possible goals or applications related to the location of DERs: Customer Responsiveness, Low-Cost Integration and Benefits Maximization. For Customer Responsiveness DER, values that should be considered include whether a system generates electricity, whether a system is sized to serve on-site load, whether a system exports power, and whether a system provides benefits to other customers. For Low-Cost Integration DER, values that should be considered include whether a system generates electricity, whether a system is sized to serve on-site or load or nearby load, a system's proximity to a substation, the voltage at the point of interconnection, the presence of other generators on the distribution line, and aggregate generation versus minimum load on the distribution line. Regarding Benefits Maximization, DERs should be considered in utility planning processes in general, and specifically when estimates for utility planning projects exceed an established cost threshold. In these cases, a cost-benefit analysis should be conducted to determine, among other things, DER integration costs compared to the value of avoided or deferred grid upgrades. For all three possible goals or DER applications, the Commission should consider the value of avoided or deferred system upgrades, as well as the value of numerous societal benefits, including economic benefits, public health benefits and reductions in greenhouse-gas emissions.

Regarding compensating DERs for the value they provide, for customer-side DG systems, Vote Solar encourages the Commission to maintain the interconnection cost waiver that is currently in place for net energy metering ("NEM") participants and non-exporting solar generators. The Commission should consider extending this waiver to new PV systems that primarily serve on-site load after the State's statutory enrollment cap for NEM is reached.

Vote Solar believes the Commission should consider two mechanisms for compensating DG sited in Benefits Maximization areas: (1) location-specific RFOs, and (2) direct compensation. Location-specific RFOs could target either general areas, such as local reliability zones, or more-specific locations, where the IOU could procure land and oversee permitting and interconnection. RFOs could be modeled on the State's Renewable Auction Mechanism, using standard contracts and existing solicitation protocols, but targeting generators located in specific locations or general areas. Bids could be compared to a pre-determined cost-effectiveness threshold that takes into account the cost of alternatives available for meeting local resource needs. IOUs should conduct RFOs for identified locations at least once every two years to test the market for DG projects that would allow an IOU to defer or avoid upgrades identified in its distribution planning. IOUs could also use RFOs to procure variable resources in areas of planned storage integration. For example, storage coupled with variable DG provides a firm resource with dependable capacity.

In addition to embracing the use of location-specific RFOs, the Commission should also provide direct compensation to local distributed PV ("LDPV") -- both wholesale and customer-side -- systems sited in areas that yield avoided costs. For wholesale DG, compensation for the avoided-cost value yielded could either be added to the compensation provided to generators selected through an RFO process or provided as an "adder" through one of the Commission's feed-in tariff programs for smaller DG. For customer-side DG, direct compensation could be modeled on the CSI's incentive structure.

On a related note, there are several cost-related factors that determine the location of a DG project from a development perspective. Although the State's existing interconnection procedures facilitate DG installations in "easy to interconnect" locations (particularly for customer-side DG), there is currently no incentive to locate in Benefits Maximization areas. Providing compensation to DG projects sited in Benefits Maximization areas will ensure that the benefits of locating in such areas are factored into the development decision-making process.

5) What specific considerations and methods should be considered to support the integration of DERs into IOU distribution planning and operations?

To support the integration of DERs into IOU distribution planning and operations, it would be beneficial to all stakeholders for IOUs to provide periodically updated forecasts of customer DER adoption rates. Ideally, these forecasts would be location- or region-specific, as opposed to general and system-wide. These adoption rates should be used in load forecasts, which, in turn, should play a significant role in IOU distribution plans. DERs should be considered as alternatives to IOU system expansions in distribution planning, especially in cases where threshold requirements (involving cost and/or location) to consider DERs as an alternative to IOU system expansion are met.

Vote Solar also believes it would be beneficial for the Commission to determine and set an appropriate flat fee for interconnecting Wholesale DG in Low-Cost Integration locations, bearing in mind the goals and requirements of Public Utilities Code Section 769.

6) **What specific distribution planning and operations methods should be considered to support the provision of distribution reliability services by DERs?**

It is appropriate to recognize that seamless integration into the distribution system is the foundation of successful DER expansion and, by extension, tapping into the myriad benefits (including distribution-reliability services) that DERs can provide. Experience in another U.S. state with a rapidly evolving distribution grid – Hawaii – shows that when customers must pay for the costs of distribution upgrades to accommodate DER systems, the DER-integration process can grind to a halt. A utility's determination that an upgrade is necessary can effectively close circuits to DERs because DER customers are not inclined to pay for upgrades that may benefit other grid users. However, advanced inverter functionality, voltage-regulation equipment, energy-management systems and energy storage can avoid the need for expensive distribution upgrades, allowing customers, IOUs and developers to pursue simpler, lower-cost, customer-based DER solutions that also provide beneficial distribution reliability services.

Bearing in mind the requirements of Public Utilities Code Section 769, we recommend that the Commission undertake the following actions in order to support the provision of distribution-reliability services by DERs:

- Ensure and maximize seamless access to the distribution system for DERs.
- Expedite access to the distribution system for DERs with advanced inverters, energy-management systems and energy-storage capability that provide grid-support services.
- Allow DERs to participate in demand-response programs and tariffs.
- Ensure that all IOU customers pay a fair share of fixed distribution-system costs -- as determined by the Commission, not by the IOUs themselves.
- Encourage greater use of TOU rates to incentivize either non-exporting DG systems or DG systems that export on-peak, in order to better align load and generation.
- Maintain the interconnection cost waiver that is currently in place for NEM participants and non-exporting solar generators after the State's statutory enrollment cap for NEM is reached.
- Proactively consider customer-based solutions, such as encouraging on-site generation,

load shifting, energy efficiency and demand response, before considering expensive and infrastructure-intensive distribution-system upgrades.

- Allow existing DG customers to opt in to any new tariffs or rate mechanisms.
- Unbundle ancillary services to provide price signals for alternative supply resources.
- Develop tariffs for fleets of DERs that can be dispatched day-ahead and/or in real time to provide ramping, frequency support, voltage support, and other ancillary services.
- Establish programs to help existing DG customers retrofit equipment to provide more-advanced functionality.

7) What types of benefits should be considered when quantifying the value of DER integration in distribution system planning and operations?

Regarding Customer Responsiveness, IOU responsiveness and customer satisfaction should be considered. IOUs should forecast and incorporate customer DER adoption rates into their DRPs. By doing so, IOUs could proactively plan to serve customer demand for DERs, and DER stakeholders would gain a better understanding of the DER marketplace in California. Regarding Low-Cost Integration, potential sites should be identified and made public on maps presented on IOU web sites; IOUs can incorporate projected DER growth in those areas into their DRPs. In considering DERs as an alternative to IOU system expansion, the benefits of implementing DERs are well established. They include avoided line losses, avoided or deferred generation and T&D capacity, avoided or deferred T&D upgrades, and various economic, environmental and public health benefits.

8) What criteria and inputs should be considered in the development of scenarios and/or guidelines to test the specific DER integration strategies proposed in the DRPs?

It is important to ensure that data inputs utilized by IOUs in their proposed DRPs are derived from reliable sources and provide a reasonable forecast of customer-adoption rates for DERs. In addition, all stakeholders deserve to have a clear understanding of the scope of DERs that will need to be implemented under IOUs' DRPs in order to meet certain policy goals and mandates, including those related to DG and energy storage.

Vote Solar also believes the Commission should consider several specific criteria in the development of scenarios and/or guidelines to test the specific DER-integration strategies proposed by IOUs in their DRPs. These include: (1) criteria for comparing wires expenditures to non-wires alternatives, (2) criteria for identifying the types of contemplated wires upgrades for which DERs should be examined as an alternative and for which competitive solicitations will be issued, (3) criteria for determining Low-Cost Integration DER locations, and (4) criteria and inputs for determining and setting an appropriate flat fee for interconnecting non-net metered DERs in Low-Cost Integration locations.

9) What types of data and level of data access should be considered as part of the DRP?

Vote Solar believes all stakeholders deserve to have access to regularly updated forecasts of customer DER-adoption rates. Ideally, these forecasts would be location- or region-specific, as opposed to general and system-wide. It would also be beneficial to stakeholders for IOUs to specify any locations where specific types of DERs cannot be accommodated, and why DERs cannot be accommodated in those locations. With respect to Low-Cost Integration DERs, potential sites should be identified and made public on maps presented on IOUs' web sites. These maps should be updated as frequently as possible. They should also indicate applicable fixed costs for DER integration in those locations. This information should be included in IOUs' DRPs.

Similarly, the areas where DER integration would yield the highest value will almost certainly change over time. Utilities should identify those areas on maps and update that information regularly. Competitive solicitations should be issued to encourage the development of DERs in those locations.

Recognizing that these maps (i.e., the underlying data) and IOU DER forecasts will be dynamic, it is critical that IOUs update as frequently as possible the information they provide to the public. Doing so will ultimately result in smoother and more-efficient DER integration.

10) Should the DRPs include specific measures or projects that serve to demonstrate how specific types of DER can be integrated into distribution planning and operation? If so, what are some examples that IOUs should consider?

Vote Solar does not provide an answer to this question at this time but looks forward to reviewing other parties' responses and providing a reply on September 22, 2014.

11) What considerations should the Commission take into account when defining how the DRPs should be monitored over time?

In defining how IOUs' DRPs should be monitored over time, the Commission should take into account the following considerations:

- Whether DER alternatives to wires expenditures are being identified, especially in cases where threshold requirements (involving cost and/or location) are met, with competitive solicitations issued for DER development.
- Costs and cost trends regarding responses to competitive solicitations for DER development.
- Actual costs versus projected costs both for DER alternatives and wires expenditures.
- The percentage of all implemented projects accounted for by wires expenditures versus DER alternatives (both in terms of the raw number of projects and of actual overall expenditures).
- The percentage of all DERs that are implemented in Low-Cost Integration locations (as opposed to other locations).
- Actual customer DER-adoption rates versus forecasted customer DER-adoption rates.
- The average length of time and cost of interconnection for each DG project (broken down by type), and the number and nature of any interconnection-related disputes or complaints.

12) What principles should the Commission consider in setting criteria to govern the review and approval of the DRPs?

Public Utilities Code Section 769 requires each IOU to propose a DRP that identifies optimal locations for the deployment of distributed resources. As noted above, each proposal shall:

- Evaluate locational benefits and costs of distributed resources located on the distribution system. This evaluation shall be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits, and any other savings the distributed resources provides to the electric grid or costs to ratepayers of the electrical corporation.
- Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives.
- Propose cost-effective methods of effectively coordinating existing commission-approved programs, incentives, and tariffs to maximize the locational benefits and minimize the incremental costs of distributed resources.
- Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goal of yielding net benefits to ratepayers.

The Commission must consider these four requirements during the process of reviewing and ultimately approving each IOU's DRP. We previously indicated that the optimal location of DERs varies by one or more of three possible goals or DER applications: Customer Responsiveness (i.e., where customers want DERs), Low-Cost Integration (i.e., where DERs can be integrated at a low cost) and Benefits Maximization (i.e., where DERs can maximize grid benefits). Vote Solar believes that these goals or DER applications reflect the spirit of the distribution-planning objectives and locational benefits presented in Public Utilities Code Section 769, and that the Commission therefore should embrace all three of these goals/applications when reviewing and approving each IOU's proposed DRP.

13) Should the DRPs include discussion of how ownership of the distribution may evolve as DERs start to provide distribution reliability services? If so, briefly discuss those areas where utility, customer and third party ownership are reasonable?

While it would be useful to contemplate this scenario, we believe that such discussions are not the most critical element during the process of developing and approving the IOUs' 2015 DRPs. While the IOUs could be required to include in their 2015 DRPs a discussion of how and why ownership structures might evolve in the future, the near-term focus should be on meeting the requirements of Section 769 even if ownership structures do not change. Accordingly, in this proceeding, with respect to Question 13, we do not recommend any changes to existing policy at this time.

14) What specific concerns around safety should be addressed in the DRPs?

All stakeholders surely agree that maintaining system safety and reliability is a critical outcome of this proceeding. System design should facilitate compliance with Rule 2. With respect to interconnection procedures, we believe that Rule 21 adequately and appropriately addresses safety issues for DG systems and energy-storage systems capable of exporting power. In considering non-wires alternatives, including Benefits Maximization scenarios and the determination of Low-Cost Integration locations, safety and reliability should absolutely be taken into account.

15) What, if any, further actions, should the Commission consider to comply with Section 769 and to establish policy and performance guidelines that enable electric utilities to develop and implement DRPs? Attachment 1 to this order is a complete copy of AB 327 as enacted.

Public Utilities Code Section 769 requires each IOU to submit a proposed DRP to the Commission on or before July 1, 2015. It does not restrict the Commission from expanding this requirement, and it generally provides the Commission with broad authority to oversee the development of individual DRPs.

The distribution system is increasingly dynamic, primarily due to the integration of various forms of DERs. It is very likely that additional investments in the distribution grid will be necessary in order to accommodate the expansion of DERs. Vote Solar believes that these investments can and should be offset by reductions in new generation and transmission capacity, and that the Commission should oversee the process of achieving this outcome.

In addition, Public Utilities Code Section 769 does not specify the frequency of the process of submitting, reviewing, modifying (if necessary) and approving proposed DRPs. In recognizing that the distribution system is increasingly dynamic, we believe it is appropriate for the Commission to require that proposed DRPs be submitted, reviewed, modified (if necessary) and approved annually. An annual planning cycle would update the Commission and stakeholders periodically to address new challenges and opportunities that surely will emerge as the distribution grid grows more sophisticated and diverse.

Lastly, Vote Solar would like to share with the Commission and other stakeholders in this proceeding a salient concept paper published by Sandia National Laboratories and the Interstate Renewable Energy Council, Inc. (IREC). The *Integrated Distribution Planning Concept Paper,*[2] published in May 2013, proposes an approach to proactive planning for DG growth -- Integrated Distribution Planning (IDP) -- that is drawn from a variety of efforts contemplated or implemented in IOU service territories from around the United States. These efforts seek to plan proactively for DG growth and anticipate distribution-system upgrades that may be necessary to accommodate both DG and load growth. By combining interconnection and distribution planning, a utility can consider upgrades that can be shared between interconnecting projects, across any number of distribution feeders or a network, or between load and generation. This approach results in distribution upgrade costs that can be spread more evenly among the parties that benefit, allowing IOUs to use DG to defer investments targeting load. Moreover, these upgrades can be planned more efficiently, where DG projects and load can share the cost of an upgrade that benefits both.

16) Appendix B to this rulemaking is a white paper that articulates one potential set of criteria that could govern the IOUs DRPs. Please review the attached paper and answer the following questions:

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[2] Sandia National Laboratories and the Interstate Renewable Energy Council, Inc. (IREC), *Integrated Distribution Planning Concept Paper*, May 2013. Available at http://www.irecusa.org/wp-content/uploads/2013/05/Integrated-Distribution-Planning-May-2013.pdf.

- **Integrated Grid Framework: the paper opens by presenting an 'Integrated Grid Framework,' what additions or modifications would you suggest be made to this framework?**

The *More Than Smart* paper attached to the OIR as Appendix B offers a number of interesting ideas that are worthy of further consideration in this proceeding. However, many of the paper's suggestions focus on guiding principles that in many cases are not well explained or supported. As well, the paper lacks specific policy recommendations that will be necessary to implement the DRP provisions of A.B. 327. Vote Solar looks forward to working with the Commission and stakeholders to identify specific policies that can be effectuated through the DRPs to achieve some of the goals identified in the paper. Vote Solar offers no additions or modifications to the "Integrated Grid Framework" at this time but reserves the right to comment further in reply comments.

- **Integrated Distribution Planning: what, if any, additions or modifications would you suggest to the Integrated Distribution Planning section of this paper?**

The paper asserts that a challenge for distribution planning is that there is no current analytical framework to address the inherent trade-off between economic optimization and operational robustness. (*See* page 9.) Vote Solar agrees. In response to Question 8, we propose that the Commission consider several specific criteria in the development of scenarios and/or guidelines to test the specific DER-integration strategies proposed by IOUs in their DRPs. These include: (1) criteria for comparing wires expenditures to non-wires alternatives, (2) criteria for identifying the types of contemplated wires upgrades for which DERs should be examined as an alternative and for which competitive solicitations will be issued, (3) criteria for determining Low-Cost Integration DER locations, and (4) criteria and inputs for determining and setting an appropriate flat fee for interconnecting non-net metered DERs in Low-Cost Integration locations.

The criteria developed should take into account the inherent trade-off between economic optimization and operational robustness.

The paper also states "qualified access to grid asset and operational data is needed." (*See* page 9.) Again, we agree. In response to Question 9, we offer specific proposals regarding the types of data and level of data access that should be considered as part of the DRPs. We also propose monitoring criteria in response to Question 11 and propose that the information provided by IOUs in DRPs be updated annually in responding to Question 15.

The paper also states that "[a] key challenge for determining value as well as the timing and magnitude of grid investment is the uncertainty related to the diffusion patterns for DER, energy efficiency, electric vehicles, microgrids and zero net energy home compliance." (*See* page 10.) In the responses above, Vote Solar proposes that all stakeholders have access to regularly updated forecasts of customer DER-adoption rates (*see* answer to Question 9). We propose that the Commission should monitor actual customer DER-adoption rates versus forecasted customer DER-adoption rates (*see* answer to Question 11). Finally, we propose that the Commission require this information to be updated annually (*see* answer to Question 15).

- **Distribution System Design-Build: what, if any, additions or modifications would you suggest to the Distribution System Design-Build section of this paper?**

This section of the paper refers repeatedly to moving toward a "network model" or "node-friendly network" for the distribution grid. (*See* pages 12-16.) These concepts are not well explained or supported in the paper, so it is difficult to understand precisely what is being proposed. Vote Solar notes that several California utilities have networked portions of their distribution grids. For example, we understand such configurations exist in portions of downtown San Francisco, Oakland and Sacramento. As well, Southern California Edison has networked portions of its high voltage distribution system in the rural, high desert areas of its service territory. Vote Solar understands that these networked distribution grids have presented challenges for integrating DG because reverse power flows can interact negatively with network protection devices. In fact, Vote Solar is aware that there are utilities in other states that will not allow DG to be interconnected to their networked systems; other utilities require significant upgrades or export control devices as a condition of interconnection. Accordingly, Vote Solar believes the paper's proposals regarding a "network model" or "node-friendly network" for the distribution grid should be carefully considered.

- **Integrated Distribution System Operations: what, if any, additions or modifications would you suggest to the Integrated Distribution System Operations section of this paper?**

Vote Solar offers no additions or modifications to the "Integrated Distribution System Operations" at this time but reserves the right to comment further in reply comments.

- **Integration of DER into Operations: what, if any, additions or modifications would you suggest to the Integration of DER into Operations section of this paper?**

Vote Solar generally agrees that the Commission should create opportunities for qualified DER to contribute to the optimization and operation of markets and the grid, and reduce the barriers and costs to participation. In these responses, we propose that the Commission should:

- Ensure and maximize seamless access to the distribution system for DERs.
- Expedite access to the distribution system for DERs with advanced inverters, energy-management systems and energy-storage capability that provide grid-support services.
- Allow DERs to participate in demand-response programs and tariffs.
- Unbundle ancillary services to provide price signals for alternative supply resources.
- Develop tariffs for fleets of DERs that can be dispatched day-ahead and/or in real time to provide ramping, frequency support, voltage support, and other ancillary services.

See answer to Question 6.

- **Integrated Grid Roadmap: what, if any, additions or modifications would you suggest to the Integrated Grid Roadmap section of this paper?**

Vote Solar offers no additions or modifications to the "Integrated Grid Roadmap" at this time but reserves the right to comment further in reply comments.

CONCLUSION

Vote Solar appreciates the opportunity to submit these responses to the questions presented in the Commission's OIR in this proceeding.

Respectfully submitted on September 4, 2014.

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